Attachment 1:

Gas Transmission Northwest
Compressor Station No. 13 – Four Factor Analysis

This attachment includes the four factor analysis for Compressor Station Number 13.

Four-Factor Analysis for Compressor Station No. 13

Gas Transmission Northwest (GTN) Compressor Station No. 13 is located near Chemult, Oregon and operates under Oregon DEQ permit number 18-0096-TV-0l. In a December 23, 2019 letter, DEQ requested a "four factor" analysis associated with its regional haze second planning period (Round 2) State Implementation Plan (SIP). This document provides the four factor analysis conducted for the facility. The analysis considers application of NOx control on the facility combustion turbines, following EPA's draft guidance document[1], standard methodologies from the EPA Control Cost Manual that are recommended in section 7 of the EPA guidance document, and recommendation (e.g., 20 year amortization for control costs) from DEQ support material.

When assessing NOx control cost effectiveness, DEQ has requested that uncontrolled NOx emissions be based on "PSEL". The associated emissions (tons per year) accounts for actual emissions based on source test results, but assumes maximum operating time, i.e., 8,760 hours annually. In contrast, EPA's Regional Haze Guidance document recommends using operations projected for 2028. Interstate natural gas transmission lines are regulated by the Federal Energy Regulatory Commission, and are designed to meet peak short-term natural gas demand, which rarely occurs. Thus, typical operation for many units is much lower than the annual hours associated with DEQ's PSEL annual emissions. That utilization is documented for past operations at Station 13, and annual operations commensurate with PSEL annual limits is not anticipated in future years. Thus, this analysis presents economic analysis for NOx control (i.e., cost per ton of NOx removed) assuming three scenarios for annual operation for each unit: PSEL-based operation, past operations, and projected future operation.

Station 13 includes two Cooper Rolls Coberra 125 simple cycle natural gas-fired combustion turbines (Units 13C and 13D) rated at 14,300 horsepower (hp). Each turbine drives a natural gas compressor and uses "diffusion flame" burner technology, consistent with the state of the art when the units were built and installed. The facility also includes a small emergency generator. Control cost effectiveness is not reviewed for the emergency generator in the four factor analysis because of its very limited run time.

As documented in the EPA NSPS for combustion turbines (40 CFR, Part 60, Subpart KKKK), the current state of the art for new turbines is "lean premixed combustion" technology, which offers lower NOx emissions than diffusion flame burners. However, the manufacturer does not offer a burner retrofit option for lean premixed combustion, and after-market options for lean premixed combustion are not available. Thus, the analysis considers other control options. Despite the lack of retrofit burner technology, turbines with diffusion flame burners are still

[1] Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period, EPA document number EPA-457/P-16-001 (July 2016).

relatively low emitting combustion sources (i.e., emissions are relatively low in comparison to other combustion devices such as reciprocating engines or units that burn other types of fuel).

Regarding SO_2 emissions, the emissions inventory calculation is based on fuel sulfur content of 1 grain per 100 SCF. However, actual sulfur content is much lower. Fuel analysis is conducted regularly, and measured values are nearly an order of magnitude lower. The average value from two years of daily gas analyses (2018 and 2019) is 0.15 grains per 100 SCF. The annual facility SO_2 emissions in the emission inventory are less than 5 tons per year (TPY) assuming the higher value, so actual emissions based on gas analysis results indicate emissions are significantly lower than 1TPY. Because SO_2 emissions are very low from units firing pipeline quality natural gas, no additional discussion of SO_2 emissions is included in this analysis. Similarly, fine particulate (PM_{10} or $PM_{2.5}$) emissions are very low for natural gas-fired turbines and no additional analysis is conducted.

Factor #1 – NOx Emissions Controls and Control Cost

The pollutant of concern for a natural gas-fired turbine is nitrogen oxides (NOx). As noted above, the Cooper Rolls Coberra turbines at the site do not have a low NOx combustor (lean premixed combustion) retrofit option. The EPA guidance document indicates that both retrofit and replacement should be considered. However, replacement costs for a 14,300 hp unit would be exorbitant.

Replacement

An approximate, "rule of thumb" cost of replacing existing compressor drivers is $3,000 per horsepower or more. Recent corporate review for similar turbines indicated replacement costs exceeding $50 million and costs ranging from $3,500 to $5,000 per horsepower. In comparison, retrofit costs for selective catalytic reduction (SCR) discussed below are less than $400 per hp (see Table 1, "Total Capital Investment" costs). Thus, capital investment for replacement is more than an order of magnitude higher than the analysis presented below to achieve a similar reduction in NOx emissions. Cost effectiveness values for NOx control would exceed $100,000 per ton for unit replacement. Notably, SCR technological concerns (discussed below) could force a choice between a technology that could impact reliability (and unit availability to meet gas demand) and exorbitant costs. Replacement is not discussed further in this analysis.

Add-on retrofit controls

Since combustion control is also not an option, the remaining add-on control technologies applicable to the combustion turbines are selective catalytic reduction (SCR) or water/steam injection. As discussed below, the latter is not technologically feasible. Consistent with the EPA guidance document, methodologies from the EPA Control Cost Manual are used to evaluate the NOx control cost effectiveness for SCR. A cost effectiveness analysis was not conducted for water injection due to its very limited application to industrial turbines – and associated difficulty in estimating capital and other costs. Additional discussion on water injection technical feasibility is provided below; capital costs would be higher and NOx reductions would be lower than the SCR scenario evaluated, so cost effectiveness values would be higher than the costs associated with SCR.

Other post-combustion NOx control options discussed in the literature are not applicable for combustion turbines. For example, "non-selective catalytic reduction" (NSCR) is a technology to reduce NOx emissions, but that technology only applies to reciprocating engines where the air-to-fuel ratio (AFR) is controlled so that there is no excess combustion air (i.e., exhaust O_2 levels are close to zero). At these conditions, species such as ammonia naturally occur in the combustion exhaust and those species participate in catalytic reactions to reduce NOx. This combustion configuration and AFR is not applicable to combustion turbines. Another technology, "selective non-catalytic reduction" (SNCR) employs similar "ammonia + NOx" chemistry, with ammonia injected at higher temperatures to reduce NOx without the use of a catalyst. In contrast, similar chemistry occurs with SCR technology but a catalyst is required for reactions to occur because the exhaust temperature is cooler. SNCR has been applied in limited cases to large boilers (e.g., utility scale electric generating units), where the boiler configuration provides ample residence time at a temperature of about 1700 °F. A very specific temperature range and residence time within that range is required for SNCR to function. Neither the temperature or residence time is available in a combustion turbine, thus SNCR is not applicable to turbines. SCR is the only potential technology, and an SCR control cost analysis follows. That discussion is preceded by a review of water/steam injection technical feasibility.

Water injection control analysis

Water injection control is a technology that was applied to turbines over two decades ago, but has had very limited use in recent years, as either combustion controls or SCR have been employed. A key concern with water injection is significant increases in emissions of products of incomplete combustion such as carbon monoxide (CO). NOx reductions would be lower than for the SCR analysis discussed above. For example, a NOx reduction of 75% may be possible at full load, but at the reduced load operation, lower uncontrolled NOx emissions and less reduction would be anticipated. When water injection was employed in limited cases, a five to eight fold increase in CO was likely; similarly, CO emissions would increase further when operating at less than full load. This may necessitate installation of an oxidation catalyst, with a cost similar to the NOx technology costs.

Turbine performance would also likely be negatively affected due to operational challenges, because this technology has not been demonstrated for natural gas transmission facilities. Water/steam injection technology was supplanted by low emissions combustion over 20 years ago, and combustion options are not available for the Coberra turbines at station 13. GTN believes that environmental and technological issues result in a conclusion that water/steam injection is not technologically feasible. A cost effectiveness analysis is not presented, but would likely show a higher cost per ton than the SCR analysis presented below. Costs would be incurred beyond base costs for NOx control and performance issues would arise, including: (1) addressing emissions of CO and other products of incomplete combustion, (2) contingencies associated with implementing a technology with very limited historical application and no installations at compressor stations in recent years, and (3) deleterious operational affects from lower unit efficiencies (e.g., more fuel use) and potential combustion instability when implementing the technology, especially when operating at other than full load.

SCR control analysis

SCR has had limited application as a retrofit control option for natural gas-fired compressor drivers. A case study for a retrofit application in California and related SCR review[2,3] showed significant problems, system re-engineering, and ultimately revisions to permit limits, including higher emission limits for ammonia slip. A more recent installation on a compressor driver also presented technological challenges and added costs associated with: exhaust temperature requirements and supplemental systems required to manage temperature over the operating range of the unit; reagent feed rate control system upgrades required to meet NOx requirements; commissioning challenges that increases anticipated schedule and costs by more than a factor of two; and managing safety issues associated with ammonia handling triggering OSHA Process Safety Management (PSM) requirements for the facility. As noted above, these raise serious questions regarding SCR performance, reliability, and technological feasibility. Thus, an operator would need to consider these operational risks versus the high costs associated with replacement if NOx mitigation is required. Additional review of technological challenges for SCR application to compressor drivers is currently being conducted by the Pipeline Research Council International (PRCI), a collaborative research group. Findings that supplement the information above may be provided at a later date if available on a timely basis.

Rather than providing additional details on technological feasibility, the SCR cost analysis is presented to assess economic feasibility. The analysis primarily relies on Control Cost Manual methods and related EPA support documentation. A key input for the analysis is the capital cost, and a 2016 Control Cost Manual (CCM) supplement that updated the SCR chapter[4] of the CCM was used to estimate the capital cost. Capital cost is based on information provided in Table 2.1b of the document.

Table 1 presents the cost details and source specific itemized cost elements following EPA Control Cost Manual methodology for Unit 13D. The results for Unit 13C (assuming the same utilization) are nearly identical (see emission rate difference explained below). Primary assumptions and inputs for the analysis include:

- A capital cost of $2,765,000 to achieve 75% reduction in NOx, based on Chapter 2 of the Control Cost Manual. The Control Cost Manual Table 2.1b information for SCR cost is $167 per kilowatt (in 1999$) for a 12 MW unit. The unit rating of 14,300 hp is approximately 10.66 MW, so the 12 MW example provided by EPA is reasonable for the Coberra turbines at station 13. The cost is adjusted from 1999 to 2020 using the consumer price index (CPI), and the CPI adjustment factor is 1.553.
- Utilization / annual operating hours: NOx emissions based on the PSEL consider the emission rate based on source test data but assume full capacity operation (i.e., 8,760 hours per year). As noted above, compressor stations on interstate pipelines are regulated by FERC and site capacity is designed to meet peak natural gas demand, which rarely occurs. Thus, utilization at compressor stations is typically well less than full capacity. As reflected in the DEQ letter

[2] L. Sasadeusz, G. Arney, et.al., "Establishing "Achieved in Practice" Emission Limits For a Simple Cycled Gas Compressor Operating Under Variable Speed", Gas Machinery Conference, Nashville, TN, October 2002.

[3] G. Arney, D.B. Olsen, and R. Mayces, "Challenges in Retrofitting Selective Catalytic Reduction (SCR) Systems to Existing Stationary Natural Gas Fired Engines", GMRC Gas Machinery Conference, Nashville, TN, Oct 2-5, 2011.

[4] "Chapter 2, Selective Catalytic Reduction," EPA update to Control Cost Manual, Table 2.1b (May 2016). Cost based on cost estimate presented in Table 2.1b for 12 MW unit.

requesting this analysis (i.e., by comparing 2017 emissions to potential emissions), run time at the facility has typically been less than 20% of maximum annual operating hours. DEQ has requested cost effectiveness analysis based on PSEL (i.e., 100% utilization), but sensitivity to assumed operating hours is presented in this analysis. The following utilization basis is included:

- Assume 100% utilization. This is the value assumed for the detailed cost effectiveness computation presented in Table 1. This value is not consistent with past operations, future projections, or recommendations in EPA's regional haze guidance.
- Assume utilization based on recent operations. Table 2 presents the last three years of fuel use and utilization for the two units at station 13. The average utilization from the last three years is used in the analysis. The average utilization for Unit 13C was 20.7% (1,816 hours) and the average for Unit 13D was 13.7% (1,202 hours).
- Assume future projected utilization. EPA guidance recommends projecting utilization in 2028. GTN projections assume pipeline system conditions may result in marginally higher future operations at Station 13 and 40% is projected for both units.

- <u>NOx emission rate</u>: Based on test results, the PSEL emission rate for Unit 13D is 172.9 lb/MMSCF of natural gas combusted. For Unit 13C, the rate is marginally lower at 164.7 lb/MMSCF. With an estimated heat rate of 9,500 Btu/hp-hr (high heating value basis), the uncontrolled NOx emission factor is 0.170 lb/MMBtu for Unit 13D and 0.161 lb/MMBtu for Unit 13C. This is appropriate for full load operation, but annual fuel use data indicates operations are often not at full load. Thus, NOx emissions are conservatively high in the analysis.
  - Based on the information above. the NOx emission rate prior to SCR control is 23.1 lb/hr for Unit 13D and 21.9 lb/hr for Unit 13C.
- Capital cost recovery is based on a twenty year life and interest rate of 5%. Longer life is not appropriate for catalytic systems *which typically have a warranty of no longer than five years*. It would be reasonable to assume a shorter life for capital recovery due to the system warranty. The twenty year life is conservatively high and consistent with recommendation in DEQ's Four Factor Analysis Fact Sheet. The interest rate assumed is a reasonable assumption, and a higher interest rate (e.g., 7%) is often used in control cost analysis to reflect the time value of money over a 20 year period. DEQ's Fact Sheet recommends using the current bank prime rate, but the current value (3.25%) is suppressed due to the highly unusual current economic situation and is not appropriate. The interest rate affects the capital recovery factor (CRF) in the analysis, but assuming the lower rate does not significantly impact the cost per ton value (i.e., less than 10%). While not presented in detail, capital cost recovery based on 10 years rather than 20 years is more appropriate based on system warranties and the lack of a proven record for application to compressor drivers. A ten year timeframe increases the cost effectiveness values below by approximately 30%.
- Most other costs (direct and indirect installation costs, etc.) are based on the Control Cost Manual.
- Reagent cost is based on a cost estimate of $700 per ton for ammonia and a molar ratio (NOx / NH_3) of 1.1. The ammonia cost is based on information available on-line from the U.S. Department of Agriculture[5] for the cost of ammonia, which varies depending on market

[5] Anydrous ammonia price fluctuates; $700 per ton is within range in recent years. For example, see U.S. DOA worksheets Table 7 and 8 at: https://www.ers.usda.gov/data-products/fertilizer-use-and-price/ and figures at:

conditions. In recent years, cost has ranged from about $500 to over $800 per ton. A cost of $700 per ton is assumed in the analysis. The cost effectiveness value is relatively insensitive to nominal changes in this cost.

The cost effectiveness results for Units 13C and 13D are summarized in the following table for the different utilization assumptions. The value ranges from $11,449 to $81,464 per ton.

	SCR Control Cost Effectiveness ($ per ton)		
Assumed utilization:	100%	2017 – 2019 Actual	Future projection
Unit 13C	$12,071/ton	$57,029/ton	$32,657/ton
Unit 13D	$11,449/ton	$81,464/ton	$30,945/ton

Assuming 100% utilization, SCR cost is over $10,000 per ton. Based on more appropriate utilization assumptions, the cost effectiveness exceeds $30,000 per ton. GTN believes these values exceed a reasonable cost threshold. In addition, as discussed above, there are questions regarding the technological feasibility of applying SCR to compressor drivers. For example, the discussion above on SCR technological feasibility identifies a case study where SCR costs were more than double anticipated costs due to commissioning and operational issues. The Control Cost Manual methodology used for this analysis does not account for such significant contingencies. Based on lessons learned from that case study, technological challenges could double the cost effectiveness values presented. As discussed below under Factor 3, there are also deleterious energy and environmental implications.

Factor #2 – Time Necessary for Compliance

Retrofitting SCR would require a timeline of three years or more. This time is required for engineering design, permitting, site preparation, installation, commissioning, and startup. A schedule up to five years could be required because previous retrofit installations of SCR on natural gas transmission compressor drivers are very limited, and have resulted in extended commissioning periods to address performance issues with the reagent control system (e.g., ability of the reagent flow control to adequately respond to emissions changes as pipeline demand changes turbine load and NOx emissions). The schedule would also need to consider the timing of facility outage to ensure that natural gas demand is not affected by the lost compression capacity.

Factor #3 – Energy and Other Environmental Impacts

SCR for NOx results in a fuel penalty and requires use of electricity to drive reagent pumps. Performance loss and electrical usage would increase greenhouse gas (GHG) emissions from the facility. SCR would also introduce other air impacts – e.g., ammonia emissions. Ammonia can form ammonium nitrate in the atmosphere and is a a particulate precursor. Thus, depending on the local atmospheric chemistry, an increase in ammonia emissions could actually exacerbate particulate matter formation. There are additional environmental impacts associated with ongoing ammonia transportation to the facility, and catalyst production and disposal.

Factor #4 – Remaining Useful Life of the Source

https://www.michfb.com/MI/Farm_News/Content/Crops/Adjusting_nitrogen_plans_based_on_fertilizer_prices_trends/

As noted in the EPA guidance document, control technology life will likely be shorter than the expected life of the stationary source. That is the case for a combustion turbine. The cost analysis assumes control technology life of twenty years for SCR. A twenty year lifetime exceeds typical estimates for emission control analysis presented in a U.S. Department of Energy (DOE) report[6], control technology analysis in EPA regulations and regulations from other states, and greatly exceeds the technology warranty. The turbine life is longer and not limited if standard maintenance requirements are followed.

Summary

In summary, the four factor analysis indicates a NOx cost effectiveness for applying SCR to the Cooper Rolls Coberra turbines that exceeds $30,000 per ton if utilization rates are based on recent operations or future projections. If 100% utilization is assumed, the cost effectiveness exceeds $11,000 per ton. This conservative utilization assumption significantly lowers the cost effectiveness value, but is not consistent with EPA regional haze guidance recommendations. Assuming full use also does not consider the unique attributes of interstate natural gas transmission compressor stations, where FERC criteria require system design to meet peak demand, but stations characteristically operate operations far less than full time. In addition, there are questions about technological feasibility for retrofitting SCR to an existing compressor driver turbine, and an SCR case study discussed above indicates SCR costs (and thus cost effectiveness values) could double due to technological challenges. There are deleterious impacts on energy (e.g., efficiency loss), the environment (e.g., ammonia emissions), and other factors (e.g., catalyst disposal, ammonia transportation and use). GTN recommends no further control requirements for the turbines at compressor station 13.

[6] "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines," Department of Energy, Prepared by ONSITE SYCOM Energy Corporation under Contract No. DE-FC02-97CHIO877 (November 1999).

Table 1. Unit 13D Rolls Royce Coberra Turbine SCR NOx Control Cost Effectiveness (100% utilization case).

	NOx Control Cost Effectiveness Estimate					
	Engine Manufacturer	Cooper-Rolls				
	Model No.	Coberra 125				
	Engine Type					
	Fuel Used	Natural Gas				**Color Legend**
	Emissions Control	SCR				User Data / Information Input Cell
	Combustion Control Purpose	NOx				"Cumulative" Cost Cell for Primary Categories
	Target Reduction	75%				Cost Effectiveness ($ / ton)
1	**Engine Design Conditions**					**Comments**
	Power Output	14300	(hp)			Rated HP
	Engine Exhaust Temperature		(F)			*optional input*
	Engine Exhaust Rate		(lb/hr)			*optional input*
	Gas Volume		(dscfm)			*optional input*
2	**Full Load Engine Exhaust Composition:**					**Comments**
	Oxygen (O_2)		(vol. %)			*optional input*
	Carbon Dioxide (CO_2)		(vol. %)			*optional input*
	Water (H_2O)		(vol. %)			*optional input*
	Oxides of Nitrogen (NOx)		(ppmvd)			*optional input*
	Nitrogen (N_2)		(vol. %)			*optional input*
	NOx	23.1	lb/hr	0.170	(lb/MMBtu)	NOx emissions from test data: 172.9 lb/MMSCF ~0.170 lb/MMBtu
3	**Engine Parameters**					**Comments**
	Total Operating Hours per Season	8760	(hrs)	100%	utilization	
4	**Final Exhaust Gas Composition**					**Comments**
	Oxides of Nitrogen (NOx)	5.8	lb/hr	0.043	(lb/MMBtu)	Assume 75% reduction
5	**Economic Parameters**					**Comments**
	Source of Cost Data	see Analysis				Analysis primarily relying on EPA Cost Manual
	Direct Costs		**Cost Formula**			**Comments**
	Combustion Control Equipment and Auxiliary Equipment	$2,765,000	(A)			Based on EPA control cost manual ($167/kw ; adjust to 2020$)
	Instrumentation	$276,500	(0.1*A)			Calculated Cost using EPA Control Cost Manual
	Sales Taxes	$91,245	(0.03*(A+instrumentation))			3% Sales Tax in this example
	Freight	$138,250	(0.05*A)			Calculated Cost using EPA Control Cost Manual
	Purchased Equipment Cost (PEC)	**$3,270,995**	PEC			
6	**Direct Installation Costs**		**Cost Formula**			**Comments**
	Foundations and Supports	$261,680	(0.08*PEC)			Calculated Cost using EPA Control Cost Manual
	Handling and Erection	$457,940	(0.14*PEC)			Calculated Cost using EPA Control Cost Manual
	Electrical	$130,840	(0.04*PEC)			Calculated Cost using EPA Control Cost Manual
	Piping	$65,420	(0.02*PEC)			Calculated Cost using EPA Control Cost Manual
	Insulation for ductwork	$32,710	(0.01*PEC)			Calculated Cost using EPA Control Cost Manual
	Painting	$32,710	(0.01*PEC)			Calculated Cost using EPA Control Cost Manual
	Site Preparation	$0	SP			As required
	Buildings	$0	Bldg			As required
	Total Installation Cost (TIC)	**$981,300**				
	Total Direct Costs (PEC+TIC)	**$4,252,295**				

Table 1 (continued).

7	**Indirect Costs**		**Cost Formula**			**Comments**
	Engineering	$327,100	(0.10*PEC)			Calculated Cost using EPA Control Cost Manual
	Construction and field expenses	$163,550	(0.05*PEC)			Calculated Cost using EPA Control Cost Manual
	Contractor fees	$327,100	(0.10*PEC)			Calculated Cost using EPA Control Cost Manual
	Start-up	$65,420	(0.02*PEC)			Calculated Cost using EPA Control Cost Manual
	Performance test	$32,710	(0.01*PEC)			Calculated Cost using EPA Control Cost Manual
	Contingencies	$98,130	(0.03*PEC)			Calculated Cost using EPA Control Cost Manual
	Total Indirect Costs (IC)	**$1,014,008**	(0.31*PEC)			
8	**Capital Cost Summary**					**Comments**
	Total Direct Capital Costs (DC)	$4,252,295				
	Total Indirect Capital Costs (IC)	$1,014,008				
	Total Capital Investment (TCI)	**$5,266,303**				
9	**Direct Annual Costs**		**Cost Formula**			**Comments**
	Operator Labor	$12,500	nominal cost			0.5 hr/shift; example from similar EPA analysis
	Supervisor Labor	$1,875				15% of operator
	Operating Materials - ammonia	$23,789				materials estimate annual NH3 at $700 per ton; 1.1 molar ratio
	Maintenance - Labor	$12,500	nominal cost			0.5 hr/shift; rate example from EPA
	Maintenance - Materials	$5,000	nominal cost			Engineering Estimate
	Catalyst maintenance / replacement	$138,250				Engineering Estimate (5% of Cap Cost)
	Testing and QA/QC	$20,000				Engineering estimate - Annual test; reagent controller QA
	Electricity	$2,500				Estimate based on analysis in PA DEP TSD
	Total Direct Annual Costs	**$216,414**				
10	**Indirect Annual Costs**		**Cost Formula**	**Capital Recovery Factor**		**Comments**
	Overhead	$19,125	(0.6*(OL+SL+ML+MM))			
	Administrative Charges	$105,326	(0.02*TCI)			Engine ACT Document
	Property Taxes	$52,663	(0.01*TCI)			Engine ACT Document
	Insurance	$52,663	(0.01*TCI)		**CRF**	
	Capital Recovery	$422,358	CRF[TCI]		0.0802	Factor for costs annualized over 20 years at 5% interest.
	Total Indirect Annual Costs	**$652,135**			CRF = i * (1+i)^n / [(1+i)^n - 1] (i expressed as a decimal - e.g., 10% = 0.1)	
11	**Summary**					**Comments**
	Total Direct Annual Operating Costs	$216,414				
	Total Indirect Annual Operating Costs	$652,135				
	Total Annual Costs	$868,549		$61	$ per hp	
	Incremental Annual Costs Over Baseline	$868,549				
12	**Annual Emissions Reduction Over Baseline**					**Comments**
	Oxides of Nitrogen (NOx)	75.87	(Tons)			
	Cost Effectiveness ($/Ton)					**Comments**
	Oxides of Nitrogen (NOx)	$11,449				

Table 2. 2017 – 2019 Operating Hours and Fuel Use for Station 13 Turbines.

Year	Unit	Hours	Fuel Used (MMscf)	Annual Average Hourly Fuel Rate (Mscfh)
2017	13C	1,048	131.6	125.6
2018	13C	2,990[A]	385.4	128.9
2019	13C	1,409	162.5	115.3
2017	13D	1,434	189.4	132.1
2018	13D	967	126.7	131.0
2019	13D	1,204	134.7	111.9

[A] The value reported in the 2018 emission inventory (2,325.75 hours) was found to be erroneous. The corrected value is shown.